ENERGY PARTNERS LTD
Form 10-Q
August 02, 2012
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

(Mark One)

x **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15 (d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended June 30, 2012

OR

¨ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15 (d) OF THE SECURITIES EXCHANGE ACT OF 1934**

Commission file number: 001-16179

ENERGY PARTNERS, LTD.

(Exact Name of Registrant as Specified in Its Charter)

Delaware	**72-1409562**
(State or Other Jurisdiction of Incorporation or Organization)	**(I.R.S. Employer Identification Number)**
201 St. Charles Ave., Suite 3400 New Orleans, Louisiana	**70170**
(Address of principal executive offices)	**(Zip code)**

(504) 569-1875

(Registrant s telephone number, including area code)

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No ¨

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x No ¨

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or smaller reporting company. See definitions of large accelerated filer , accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act.

Large accelerated filer	¨	Accelerated filer	x
Non-accelerated filer	¨ (Do not check if a smaller reporting company)	Smaller reporting company	¨

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ¨ No x

Indicate by check mark whether the registrant has filed all documents and reports required to be filed by Sections 12, 13 or 15(d) of the Securities Exchange Act of 1934 subsequent to the distribution of securities under a plan confirmed by a court. Yes x No ¨

As of July 27, 2012, there were 39,103,674 shares of the Registrant s Common Stock, par value $0.001 per share, outstanding.

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PART I FINANCIAL INFORMATION

Item 1. FINANCIAL STATEMENTS.

ENERGY PARTNERS, LTD. AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS

(UNAUDITED)

(In thousands, except share data)	June 30, 2012	December 31, 2011
ASSETS		
Current assets:		
Cash and cash equivalents	$ 60,847	$ 80,128
Trade accounts receivable net	32,620	31,817
Fair value of commodity derivative instruments	10,736	587
Prepaid expenses	9,226	11,046
Total current assets	113,429	123,578
Property and equipment, under the successful efforts method of accounting	1,220,695	1,082,248
Less accumulated depreciation, depletion, amortization and impairments	(362,644)	(305,110)
Net property and equipment	858,051	777,138
Restricted cash	6,023	6,023
Other assets	3,155	3,029
Fair value of commodity derivative instruments	3,790	
Deferred financing costs net of accumulated amortization of $1,707 at June 30, 2012 and $1,061 at December 31, 2011	4,812	5,452
	$ 989,260	$ 915,220
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities:		
Accounts payable	$ 24,911	$ 25,393
Accrued expenses	78,990	58,538
Asset retirement obligations	32,698	25,578
Fair value of commodity derivative instruments	620	1,056
Deferred tax liabilities	6,771	2,823
Total current liabilities	143,990	113,388
Long-term debt	204,750	204,390
Asset retirement obligations	67,219	73,769
Deferred tax liabilities	49,481	31,775
Fair value of commodity derivative instruments	607	190
Other	1,179	663
	467,226	424,175
Commitments and contingencies (Note 8)		
Stockholders equity:		
Preferred stock, $0.001 par value per share; authorized 1,000,000 shares; no shares issued and outstanding at June 30, 2012 and December 31, 2011		

Common stock, $0.001 par value per share; authorized 75,000,000 shares; shares issued 40,558,925 and 40,326,451 at June 30, 2012 and December 31, 2011, respectively; shares outstanding 39,103,674 and 39,404,106 at June 30, 2012 and December 31, 2011, respectively	40	40
Additional paid-in capital	507,657	505,235
Treasury stock, at cost, 1,455,251 and 922,345 shares at June 30, 2012 and December 31, 2011, respectively	(19,698)	(11,361)
Retained earnings (accumulated deficit)	34,035	(2,869)
Total stockholders equity	522,034	491,045
	$ 989,260	$ 915,220

See accompanying notes to condensed consolidated financial statements.

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ENERGY PARTNERS, LTD. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

(UNAUDITED)

(In thousands, except per share data)	**Three Months Ended June 30, 2012**	**Three Months Ended June 30, 2011**	**Six Months Ended June 30, 2012**	**Six Months Ended June 30, 2011**
Revenue:				
Oil and natural gas	$ 99,249	$ 92,798	$ 198,021	$ 160,013
Other	21	32	45	66
	99,270	92,830	198,066	160,079
Costs and expenses:				
Lease operating	18,661	17,908	37,072	33,239
Transportation	99	236	250	371
Exploration expenditures and dry hole costs	2,587	822	16,896	1,370
Impairments	3,394	2,886	5,708	13,674
Depreciation, depletion and amortization	27,918	25,522	51,826	46,585
Accretion of liability for asset retirement obligations	3,411	3,804	6,559	7,379
General and administrative	5,654	4,796	10,998	10,083
Taxes, other than on earnings	2,904	3,695	6,645	7,013
Other	3,443	1,902	3,618	2,032
Total costs and expenses	68,071	61,571	139,572	121,746
Income from operations	31,199	31,259	58,494	38,333
Other income (expense):				
Interest income	50	17	88	27
Interest expense	(5,093)	(4,974)	(9,967)	(7,444)
Gain (loss) on derivative instruments	30,305	13,831	10,243	(11,694)
Loss on early extinguishment of debt				(2,377)
	25,262	8,874	364	(21,488)
Income before income taxes	56,461	40,133	58,858	16,845
Income tax expense	(21,060)	(15,130)	(21,954)	(6,351)
Net income	35,401	25,003	36,904	10,494
Basic earnings per share	$ 0.90	$ 0.62	$ 0.94	$ 0.26
Diluted earnings per share	$ 0.90	$ 0.62	$ 0.94	$ 0.26
Weighted average common shares used in computing earnings per share:				
Basic	38,914	40,109	39,018	40,095
Diluted	39,027	40,237	39,132	40,217

See accompanying notes to condensed consolidated financial statements.

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ENERGY PARTNERS, LTD. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(UNAUDITED)

(In thousands)	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
Cash flows from operating activities:		
Net income	$ 36,904	$ 10,494
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	51,826	46,585
Accretion of liability for asset retirement obligations	6,559	7,379
Loss on early extinguishment of debt		2,377
Unrealized gain on derivative contracts	(13,958)	(3,063)
Non-cash compensation	2,318	1,276
Deferred income taxes	21,654	6,334
Exploration expenditures	4,173	131
Impairments	5,708	13,674
Amortization of deferred financing costs and discount on debt	1,004	689
Other	3,401	1,731
Changes in operating assets and liabilities:		
Trade accounts receivable	901	(9,523)
Other receivables		1,283
Prepaid expenses	1,820	(4,814)
Other assets	(78)	(13)
Accounts payable and accrued expenses	5,297	5,011
Asset retirement obligations	(19,346)	(17,359)
Other liabilities		(3)
Net cash provided by operating activities	108,183	62,189
Cash flows used in investing activities:		
Decrease in restricted cash		2,467
Property acquisitions	(33,064)	(196,350)
Exploration and development expenditures	(85,133)	(22,994)
Other property and equipment additions	(1,145)	(361)
Net cash used in investing activities	(119,342)	(217,238)
Cash flows provided by (used in) financing activities:		
Proceeds from indebtedness		203,794
Deferred financing costs	(6)	(6,189)
Purchase of shares into treasury	(8,183)	
Exercise of stock options	67	119
Net cash provided by (used in) financing activities	(8,122)	197,724
Net increase (decrease) in cash and cash equivalents	(19,281)	42,675
Cash and cash equivalents at beginning of period	80,128	33,553
Cash and cash equivalents at end of period	$ 60,847	$ 76,228

See accompanying notes to condensed consolidated financial statements.

ENERGY PARTNERS, LTD. AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(UNAUDITED)

(1) Basis of Presentation

Energy Partners, Ltd. (we, our, us, or the Company) was incorporated as a Delaware corporation on January 29, 1998. We are an independent o and natural gas exploration and production company. Our current operations are concentrated in the U.S. Gulf of Mexico shelf focusing on state and federal waters offshore Louisiana.

The financial information as of June 30, 2012 and for the three- and six-month periods ended June 30, 2012 and June 30, 2011 has not been audited. However, in the opinion of management, all adjustments (which include only normal, recurring adjustments) necessary to present fairly the financial position and results of operations for the periods presented have been included therein. Certain information and footnote disclosures normally in financial statements prepared in accordance with generally accepted accounting principles have been condensed or omitted pursuant to rules and regulations of the Securities and Exchange Commission. The condensed consolidated balance sheet at December 31, 2011 has been derived from the audited financial statements at that date. Certain reclassifications have been made to the prior period financial statements in order to conform to the classification adopted for reporting in the current period. These financial statements and footnotes should be read in conjunction with the financial statements and notes thereto included in our Annual Report on Form 10-K for the year ended December 31, 2011 (the 2011 Annual Report). The results of operations and cash flows for the first six months of the year are not necessarily indicative of the results of operations which might be expected for the entire year.

(2) Acquisitions

The South Timbalier Acquisition

On May 15, 2012, we acquired from W&T Offshore, Inc. (W&T) an asset package consisting of certain shallow-water Gulf of Mexico shelf oil and natural gas interests in our South Timbalier 41 field (the ST 41 Interests) located in the Gulf of Mexico for $32.4 million in cash, subject to customary adjustments to reflect an economic effective date of April 1, 2012 (the ST 41 Acquisition). We estimate that the proved reserves as of the April 1, 2012 economic effective date totaled approximately 1.0 Mmboe, of which 51% were oil and 84% were proved developed reserves. Prior to the acquisition, we owned a 60% working interest in the properties and W&T owned a 40% working interest. As a result of the acquisition, we have become the sole working interest owner of the South Timbalier 41 field. We funded the ST 41 Acquisition with cash on hand.

The following allocation of the purchase price as of April 1, 2012 is preliminary and includes estimates. This preliminary allocation is based on information that was available to management at the time these consolidated financial statements were prepared and is subject to revision as management finalizes adjustments to purchase price provided for by the purchase and sale agreement. Accordingly, the allocation may change as additional information becomes available and is assessed by management, and the impact of such changes may be material.

The following table summarizes the estimated values of assets acquired and liabilities assumed and reflects adjustments to purchase price provided for by the purchase and sale agreement of approximately $1.5 million to reflect an economic effective date of April 1, 2012.

(In thousands)	**April 1, 2012**
Oil and natural gas properties	$ 32,766
Asset retirement obligations	(1,878)
Net assets acquired	$ 30,888

The ASOP Acquisition

On February 14, 2011, we acquired from Anglo-Suisse Offshore Partners, LLC (ASOP) an asset package consisting of certain shallow-water Gulf of Mexico shelf oil and natural gas interests surrounding the Mississippi River delta and a related gathering system (the ASOP Properties) for $200.7 million in cash, subject to purchase price adjustments to reflect an economic effective date of January 1, 2011 (the ASOP Acquisition). As of December 31, 2010, the ASOP Properties had estimated proved reserves of approximately 8.1 Mmboe, of which 84% were oil and 76% were proved developed reserves. The primary factors considered by management in acquiring the ASOP Properties include the belief that the ASOP Acquisition provided an opportunity to significantly increase our reserves, production volumes and drilling portfolio, while maintaining our focus on oil-weighted assets in our core area of expertise in the Gulf of Mexico shelf. We financed the ASOP Acquisition with the proceeds from the sale of $210 million in aggregate principal amount of the 8.25% senior notes due 2018 (the 8.25% Notes). After deducting the initial purchasers discount and offering expenses, we realized net proceeds of approximately $202 million. See Note 5, Indebtedness, for more information regarding our 8.25% Notes.

The following table summarizes the estimated values of assets acquired and liabilities assumed and reflects adjustments to purchase price provided for by the purchase and sale agreement totaling approximately $3.8 million to reflect an economic effective date of January 1, 2011.

(In thousands)	**January 1, 2011**
Oil and natural gas properties	$ 221,751
Asset retirement obligations	(24,858)
Net assets acquired	$ 196,893

The Main Pass Acquisition

On November 17, 2011, we acquired certain interests in producing oil and natural gas assets in the shallow-water central Gulf of Mexico shelf (the Main Pass Interests) from Stone Energy Offshore, L.L.C. (the Seller) for $38.6 million in cash, subject to customary adjustments to reflect the economic effective date of November 1, 2011 (the Main Pass Acquisition). The Main Pass Interests consist of additional interests in the Main Pass 296/311 complex that was included in the ASOP Acquisition, along with other unit interests in the Main Pass complex and an interest in a Main Pass 295 primary term lease. We estimate that the proved reserves as of the November 1, 2011 economic effective date totaled approximately 2.6 Mmboe, all of which were proved developed reserves and approximately 96% of which were oil reserves. We funded the Main Pass Acquisition with cash on hand.

The following allocation of the purchase price as of November 1, 2011 is preliminary and includes estimates. This preliminary allocation is based on information that was available to management at the time these consolidated financial statements were prepared and is subject to revision. Accordingly, the allocation may change as additional information becomes available and is assessed by management, and the impact of such changes may be material.

The following table summarizes the estimated values of assets acquired and liabilities assumed and reflects adjustments to purchase price provided for by the purchase and sale agreement of approximately $0.7 million to reflect an economic effective date of November 1, 2011.

(In thousands)	**November 1, 2011**
Oil and natural gas properties	$ 39,412
Asset retirement obligations	(1,577)
Net assets acquired	$ 37,835

We have accounted for our acquisitions using the purchase method of accounting for business combinations, and therefore we have estimated the fair value of the assets acquired and the liabilities assumed as of their respective acquisition dates. In the estimation of fair value, management uses various valuation methods including (i) comparable company analysis, which estimates the value of the acquired properties based on the implied valuations of other similar operations; (ii) comparable asset transaction analysis, which estimates the value of the acquired operations based upon publicly announced transactions of assets with similar characteristics; (iii) comparable merger transaction analysis, which, much like comparable asset transaction analysis, estimates the value of operations based upon publicly announced transactions with similar characteristics, except that merger analysis analyzes public to public merger transactions rather than solely asset transactions; and (iv) discounted cash flow analysis. The fair value is based on subjective estimates and assumptions, which are inherently subject to significant uncertainties which are beyond our control. These assumptions represent Level 3 inputs, as further discussed in Note 7, Fair Value Measurements.

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Results of Operations and Pro Forma Information

Revenues and lease operating expenses attributable to the ST 41 Interests, the ASOP Properties and the Main Pass Interests for the three and six months ended June 30, 2012 and 2011 were as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
	(in thousands)			
ST 41 Interests:				
Revenues	$ 1,937	$	$ 1,937	$
Lease operating expenses	$ 292	$	$ 292	$
ASOP Properties and Main Pass Interests:				
Revenues	$ 46,278	$ 35,509	$ 86,675	$ 52,005
Lease operating expenses	$ 5,448	$ 4,536	$ 12,083	$ 6,227

We have determined that the presentation of net income attributable to the ST 41 Interests, the ASOP Properties and the Main Pass Interests is impracticable due to the integration of the related operations upon acquisition. We incurred fees of approximately $0.1 million related to the ST 41 Interests, which were included in general and administrative expenses in the accompanying consolidated statements of operations for the three and six months ended June 30, 2012. We incurred fees of approximately $0.5 million related to the ASOP Acquisition, which were included in general and administrative expenses in the accompanying consolidated statement of operations for the six months ended June 30, 2011.

The following supplemental pro forma information presents consolidated results of operations as if the ST 41 Acquisition, the ASOP Acquisition and Main Pass Acquisition had occurred on January 1, 2011. The supplemental unaudited pro forma information was derived from a) our historical consolidated statements of operations, b) the statements of revenues and direct operating expenses for the ST 41 Interests, which were derived from our historical accounting records, c) the statements of revenues and direct operating expenses for the ASOP Properties, which were derived from ASOP s historical accounting records and d) the statements of revenues and direct operating expenses for the Main Pass Interests, which were derived from the historical accounting records of the Seller. This information does not purport to be indicative of results of operations that would have occurred had the acquisition occurred on January 1, 2011, nor is such information indicative of any expected future results of operations.

	Three Months Ended June 30,		Six Months Ended June 30,	
	Pro Forma 2012	Pro Forma 2011	Pro Forma 2012	Pro Forma 2011
	(in thousands, except per share data)			
Revenue	$ 101,262	$ 101,370	$ 206,879	$ 189,186
Net income	$ 36,219	$ 27,525	$ 40,132	$ 16,719
Basic earnings per share	$ 0.92	$ 0.69	$ 1.02	$ 0.42
Diluted earnings per share	$ 0.92	$ 0.68	$ 1.02	$ 0.42

(3) Earnings per Share

The following table sets forth the calculation of basic and diluted weighted average shares outstanding and earnings per share for the indicated periods.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
Income (numerator):				
Net income	$ 35,401	$ 25,003	$ 36,904	$ 10,494
Net income attributable to participating securities	(254)	(67)	(245)	(26)

Net income attributable to common shares	$ 35,147	$ 24,936	$ 36,659	$ 10,468
Weighted average shares (denominator):				
Weighted average shares basic	38,914	40,109	39,018	40,095
Dilutive effect of stock options	113	128	114	122
Weighted average shares diluted	39,027	40,237	39,132	40,217
Basic earnings per share	$ 0.90	$ 0.62	$ 0.94	$ 0.26
Diluted earnings per share	$ 0.90	$ 0.62	$ 0.94	$ 0.26

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The following table indicates the number of shares underlying outstanding stock-based awards excluded from the computation of dilutive weighted average shares because their effect is antidilutive for the periods indicated.

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	**2012**	**2011**	**2012**	**2011**
Weighted average shares	624	416	597	381

(4) Asset Retirement Obligations

Changes in our asset retirement obligations were as follows:

	Six Months Ended June 30, 2012 (in thousands)
Balance at December 31, 2011	$ 99,347
Accretion expense	6,559
Liabilities assumed in acquisition	1,878
Liabilities incurred	121
Revisions	11,358
Liabilities settled	(19,346)
Balance at June 30, 2012	99,917
Less: End of period, current portion	32,698
End of period, noncurrent portion	$ 67,219

(5) Indebtedness

The following table sets forth our indebtedness.

(In thousands)	**June 30, 2012**	**December 31, 2011**
8.25% Senior Notes, face amount of $210.0 million, interest rate of 8.25% payable semi-annually, in arrears on February 15 and August 15 of each year, mature February 15, 2018	$ 204,750	$ 204,390
Senior Credit Facility, interest rate based on base rate or LIBOR plus a floating spread, maturity date February 14, 2015		
Total indebtedness	204,750	204,390
Current portion of indebtedness		
Noncurrent portion of indebtedness	$ 204,750	$ 204,390

In connection with the ASOP Acquisition (see Note 2) on February 14, 2011, we issued $210.0 million in aggregate principal amount of our 8.25% Notes due 2018. Furthermore, our credit facility existing on that date was terminated and replaced with a new credit facility. The termination of our prior credit facility during the six months ended June 30, 2011 resulted in a loss on early extinguishment of debt of $2.4 million, primarily due to writing off the unamortized deferred financing costs associated with the terminated facility.

The 8.25% Notes

On February 14, 2011, we issued the $210.0 million in aggregate principal amount of our 8.25% Notes under an Indenture, dated as of February 14, 2011 (the Indenture). As described in Note 2, Acquisitions, we used the net proceeds from the offering of the 8.25% Notes of $202.0 million, after deducting the initial purchasers discount and offering expenses payable by us, to acquire the ASOP Properties for a purchase price of $200.7 million, before adjustments to reflect an economic effective date of January 1, 2011, and for general corporate purposes. The 8.25% Notes bear interest from the date of their issuance at an annual rate of 8.25% with interest due semi-annually, in arrears, on February 15 and August 15 of each year, commencing on August 15, 2011. The 8.25% Notes are fully and unconditionally guaranteed, jointly and severally, on an unsecured senior basis initially by each of our existing direct and indirect domestic subsidiaries (other than immaterial subsidiaries). The 8.25% Notes will mature on February 15, 2018. For additional information regarding the 8.25% Notes, see Note 7, Indebtedness, of our 2011 Annual Report.

Senior Credit Facility

On February 14, 2011, we entered our senior credit facility with BMO Capital Markets, as lead arranger, and Bank of Montreal, as administrative agent and a lender, and the other lender parties thereto (Senior Credit Facility). Upon the closing of our Senior Credit Facility, our then existing credit facility was terminated. The terms of our Senior Credit Facility established a revolving credit facility with a four-year term that may be used for revolving credit loans and letters of credit up to an aggregate principal amount of $250.0 million. The maximum amount of letters of credit that may be outstanding at any one time is $20.0 million. The amount available under the revolving credit facility is limited by the borrowing base. With the consent of the agent, we also have the ability to increase the aggregate commitments under the Senior Credit Facility by up to an additional $50.0 million to the extent that existing and/or future lenders provide additional commitments. The Senior Credit Facility is secured by substantially all of our assets, including mortgages on at least 85% of our oil and gas properties and the stock of certain wholly-owned subsidiaries. The borrowing base under our Senior Credit Facility has been determined at the discretion of the lenders, based on the collateral value of our proved reserves, and is subject to potential special and regular semi-annual redeterminations. As of May 1, 2012, we completed our semi-annual redetermination and our borrowing base remains at $200.0 million. Borrowings under our Senior Credit Facility bear interest ranging from a base rate plus a margin of 1.00% to 2.00% on base rate borrowings and LIBOR plus a margin of 2.00% to 3.00% on LIBOR borrowings. We had no amounts drawn under our Senior Credit Facility at June 30, 2012 and December 31, 2011. For additional information regarding our Senior Credit Facility, see Note 7, Indebtedness, of our 2011 Annual Report.

(6) Derivative Instruments and Hedging Activities

We enter into derivative transactions to reduce exposure to fluctuations in the price of oil and natural gas for a portion of our production. Our fixed-price swaps fix the sales price for a limited amount of our production and, for the contracted volumes, eliminate our ability to benefit from increases in the sales price of the production. Our collars limit our exposure to declines in the sales price of oil while giving us the ability to benefit from increases to a certain level in the sales price of oil for a limited amount of our production. Derivative instruments are carried at their fair value on the condensed consolidated balance sheets as Fair value of commodity derivative instruments, and all unrealized and realized gains and losses are recorded in Gain (loss) on derivative instruments in Other income (expense) in the condensed consolidated statements of operations. See Note 7 for information regarding fair values of our derivative instruments.

The following table sets forth our derivative instruments outstanding as of June 30, 2012.

Oil Contracts

	Fixed-Price Swaps		
Remaining Contract Term	Daily Average Volume (Bbls)	Volume (Bbls)	Average Swap Price ($/Bbl)
July 2012	3,394	105,200	$ 99.43
August 2012 November 2012	2,921	356,400	$ 104.05
December 2012	3,361	104,200	$ 102.80
January 2013 July 2013	3,203	679,000	$ 100.30
August 2013 November 2013	1,926	235,000	$ 103.69
December 2013	2,306	71,500	$ 102.05

	Collars		
Remaining Contract Term	Daily Average Volume (Bbls)	Volume (Bbls)	Average Strike Price ($/Bbl)
July 2012	1,000	31,000	$ 87.50/123.18
August 2012 November 2012	1,000	122,000	$ 87.50/123.18
December 2012	1,000	31,000	$ 87.50/123.18
January 2013 July 2013	1,500	318,000	$ 83.33/112.53
August 2013 November 2013	1,500	183,000	$ 83.33/112.53
December 2013	1,500	46,500	$ 83.33/112.53

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Gas Contracts

	Fixed-Price Swaps		
Remaining Contract Term	Daily Average Volume (Bbls)	Volume (Bbls)	Average Swap Price ($/Bbl)
July 2012 December 2012	1,000	184,000	$ 2.69
January 2013 December 2013	1,000	365,000	$ 3.51

The following table presents information about the components of our gain (loss) on derivative instruments:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
	(in thousands)			
Derivative contracts:				
Unrealized gain due to change in fair market value	$ 30,500	$ 23,297	$ 13,958	$ 3,063
Realized loss on settlement	(195)	(9,466)	(3,715)	(14,757)
Total gain (loss) on derivative instruments	$ 30,305	$ 13,831	$ 10,243	$ (11,694)

(7) Fair Value Measurements

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. ASC Topic 820, Fair Value Measurements and Disclosures, establishes a fair value hierarchy with three levels based on the reliability of the inputs used to determine fair value. These levels include: Level 1, defined as inputs such as unadjusted quoted prices in active markets for identical assets and liabilities; Level 2, defined as inputs other than quoted prices in active markets that are either directly or indirectly observable; and Level 3, defined as unobservable inputs for use when little or no market data exists, therefore requiring an entity to develop its own assumptions. In May 2011, the Financial Accounting Standards Board (the FASB) issued Accounting Standards Update (ASU) No. 2011-04, Fair Value Measurement (Topic 820): Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs (ASU 2011-04), which became effective for us in the quarter ended March 31, 2012. ASU 2011-04 includes additional guidance related to fair value measurement principles and additional disclosure requirements. The impact of adopting ASU 2011-04 was immaterial.

As of June 30, 2012 and December 31, 2011, we held certain financial assets and liabilities that are required to be measured at fair value on a recurring basis, primarily our commodity derivative instruments. The fair values of our derivative instruments were measured according to the market approach or, if necessary, the income approach using price inputs published by NYMEX and IntercontinentalExchange, Inc., or ICE. These price inputs include settled exchange prices and quoted prices for assets and liabilities similar to those held by us and meet the definition of Level 2 inputs within the fair value hierarchy. The following table sets forth our financial assets and liabilities that are accounted for at fair value on a recurring basis:

	June 30, 2012	December 31, 2011
	(in thousands)	
Assets:		
Fair value of commodity derivative instruments	$ 14,526	$ 587
Liabilities:		
Fair value of commodity derivative instruments	$ 1,227	$ 1,246

On May 21, 2012, we entered into an agreement with an insurance company whereby, if a named wind storm occurs in a specified area of the Gulf of Mexico and that storm meets certain strength criteria, the insurance company will pay a fixed amount of cash proceeds to us. This agreement is considered a weather derivative under the applicable authoritative guidance related to financial instruments. We recognized the premium paid as a current asset, which we are amortizing to expense over the term of the agreement. At June 30, 2012, we estimate that the fair value of this financial instrument approximates the carrying amount of approximately $2.1 million, based on the amount of premium paid, which is a Level 3 input within the fair value hierarchy.

As of June 30, 2012 and December 31, 2011, the carrying amount of our 8.25% Notes was $204.8 million and $204.4 million, respectively, which reflects the $210.0 million face amount, net of the unamortized amount of initial purchasers discount of $5.2 million and $5.6 million at June 30, 2012 and December 31, 2011, respectively. As of June 30, 2012 and December 31, 2011, we estimated the fair value of the 8.25% Notes at approximately $207.9 million and $202.7 million, respectively, based on quoted prices, which are Level 1 inputs within the fair value hierarchy.

We evaluate our capitalized costs of proved oil and natural gas properties for potential impairment when circumstances indicate that the carrying values may not be recoverable. Our assessment of possible impairment of proved oil and natural gas properties is based on our best estimate of future prices, costs and expected net future cash flows by property (generally analogous to a field or lease). An impairment loss is indicated if undiscounted net future cash flows are less than the carrying value of a property. The impairment expense is measured as the shortfall between the net book value of the property and its estimated fair value, which is measured based on the discounted net future cash flows from the property. The inputs used to estimate the fair value of our oil and natural gas properties are based on our estimates of future events, including projections of future oil and natural gas sales prices, amounts of recoverable oil and natural gas reserves, timing of future production, future costs to develop and produce our oil and natural gas and discount factors. These inputs meet the definition of Level 3 inputs within the fair value hierarchy. Impairments for the three and six months ended June 30, 2012 were primarily due to the decline in our estimate of future natural gas prices affecting certain of our natural gas producing fields and to reservoir performance of one of our natural gas producing fields. Impairments for the three and six months ended June 30, 2011 were primarily related to reservoir performance at certain of our natural gas producing fields. These fields were determined to have future net cash flows less than their carrying values resulting in their write down to estimated fair value.

As addressed in Note 2, Acquisitions, we applied fair value concepts in estimating and allocating the fair value of the ST 41 Interests, the ASOP Properties and Main Pass Interests in accordance with purchase accounting for business combinations. The inputs to the estimated fair values of the assets acquired and liabilities assumed are described in Note 2.

(8) Commitments and Contingencies

We maintain restricted escrow funds in a trust for future abandonment costs at our East Bay field. The trust was originally funded over time with $15 million and, with accumulated interest, increased to $16.7 million at December 31, 2008. We may draw from the trust upon completion of qualifying abandonment activities at our East Bay field. At June 30, 2012, we had $6.0 million remaining in restricted escrow funds for decommissioning work in our East Bay field, which will remain restricted until substantially all required decommissioning in the East Bay field is complete. Amounts on deposit in the trust account are reflected in Restricted cash on our consolidated balance sheets.

We record liabilities when we deliver production that is in excess of our interest in certain properties. In addition to these imbalances, we may, from time to time, be allocated cash sales proceeds in excess of amounts that we estimate are due to us for our interest in production. These allocations may be subject to further review, may require more information to resolve or may be in dispute. In July 2010, we were notified by a purchaser of oil production from one of our non-operated fields that we were allocated, and received sales proceeds from, more oil production than we actually sold to that purchaser. These third party misallocations may date back to 2006. The oil purchaser s initial estimate of the oil volumes misallocated to us was approximately 74,000 barrels, which may be valued at up to $6.9 million based on information provided by the oil purchaser. We have previously recorded an amount that we believe may be payable related to a potential reallocation, which amount is reflected in Accrued expenses in the accompanying condensed consolidated balance sheets as of June 30, 2012 and December 31, 2011.

We and our oil and gas joint interest owners are subject to periodic audits of the joint interest accounts for leases in which we participate and/or operate. As a result of these joint interest audits, amounts payable or receivable by us for costs incurred or revenue distributed by the operator or by us on a lease may be adjusted, resulting in adjustments, increases or decreases, to our net costs or revenues and the related cash flows. Such adjustments may be material. When they occur, these adjustments are recorded in the current period, which generally is one or more years after the related cost or revenue was incurred or recognized by the joint account.

In the ordinary course of business, we are a defendant in various other legal proceedings. We do not expect our exposure in these other proceedings, individually or in the aggregate, to have a material adverse effect on our financial position, results of operations or liquidity.

(9) New Accounting Pronouncements

In December 2011, the FASB issued ASU No. 2011-11, Balance Sheet (Topic 201): Disclosures about Offsetting Assets and Liabilities (ASU 2011-11). ASU 2011-11 requires disclosure of information about offsetting and related arrangements to enable users of financial statements to understand the effect or potential effect of netting arrangements on an entity s financial position, including the effect or potential effect of rights of setoff associated with certain financial instruments and derivative instruments. The required disclosures are effective for our annual report for the year ending December 31, 2013 and for interim periods within that year. We have not yet completed our review of the required disclosures; however, we expect the impact on our reporting to be immaterial.

(10) Supplemental Condensed Consolidating Financial Information

In connection with the 8.25% Notes offering described in Note 5, all of our existing direct and indirect domestic subsidiaries (other than immaterial subsidiaries) (the Guarantor Subsidiaries) jointly, severally and unconditionally guaranteed the payment obligations under our 8.25%

Notes. The following supplemental financial information sets forth, on a consolidating basis, the balance

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sheets, statements of operations and cash flow information for Energy Partners, Ltd. (Parent Company Only) and for the Guarantor Subsidiaries. We have not presented separate financial statements and other disclosures concerning the Guarantor Subsidiaries because management has determined that such information is not material to investors.

The supplemental condensed consolidating financial information has been prepared pursuant to the rules and regulations for condensed financial information and does not include all disclosures included in annual financial statements. Certain reclassifications were made to conform all of the financial information to the financial presentation on a consolidated basis. The principal eliminating entries eliminate investments in subsidiaries, intercompany balances and intercompany revenues and expenses.

Supplemental Condensed Consolidating Balance Sheet

As of June 30, 2012

	Parent Company Only	Guarantor Subsidiaries	Eliminations	Consolidated
		(In thousands)		
ASSETS				
Current assets:				
Cash and cash equivalents	$ 60,847	$	$	$ 60,847
Accounts receivable	84,731	135	(52,246)	32,620
Other current assets	19,962			19,962
Total current assets	165,540	135	(52,246)	113,429
Property and equipment	961,420	259,275		1,220,695
Less accumulated depreciation, depletion, amortization and impairments	(298,369)	(64,275)		(362,644)
Net property and equipment	663,051	195,000		858,051
Investment in affiliates	105,502		(105,502)	
Notes receivable, long-term		69,000	(69,000)	
Other assets	17,780			17,780
	951,873	264,135	(226,748)	989,260
LIABILITIES AND STOCKHOLDERS EQUITY				
Current liabilities:				
Accounts payable and accrued expenses	$ 132,232	$ 63,384	$ (52,246)	$ 143,370
Fair value of commodity derivative instruments	620			620
Total current liabilities	132,852	63,384	(52,246)	143,990
Long-term debt	204,750	69,000	(69,000)	204,750
Other liabilities	92,237	26,249		118,486
	429,839	158,633	(121,246)	467,226
Stockholders equity:				
Preferred stock		3	(3)	
Common stock	40	98	(98)	40
Additional paid-in capital	507,657	84,900	(84,900)	507,657
Retained earnings (accumulated deficit)	34,035	20,501	(20,501)	34,035
Treasury stock, at cost	(19,698)			(19,698)
Total stockholders equity	522,034	105,502	(105,502)	522,034
	951,873	264,135	(226,748)	989,260

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Supplemental Condensed Consolidating Balance Sheet

As of December 31, 2011

	Parent Company Only	Guarantor Subsidiaries	Eliminations	Consolidated
		(In thousands)		
ASSETS				
Current assets:				
Cash and cash equivalents	$ 80,128	$	$	$ 80,128
Accounts receivable	93,882	131	(62,196)	31,817
Other current assets	11,633			11,633
Total current assets	185,643	131	(62,196)	123,578
Property and equipment	833,932	248,316		1,082,248
Less accumulated depreciation, depletion, amortization and impairments	(251,948)	(53,162)		(305,110)
Net property and equipment	581,984	195,154		777,138
Investment in affiliates	91,768		(91,768)	
Notes receivable, long-term		69,000	(69,000)	
Other assets	14,504			14,504
	873,899	264,285	(222,964)	915,220
LIABILITIES AND STOCKHOLDERS EQUITY				
Current liabilities:				
Accounts payable and accrued expenses	$ 99,096	$ 72,609	$ (62,196)	$ 109,509
Deferred tax liabilities	2,823			2,823
Fair value of commodity derivative instruments	1,056			1,056
Total current liabilities	102,975	72,609	(62,196)	113,388
Long-term debt	204,390	69,000	(69,000)	204,390
Other liabilities	75,489	30,908		106,397
	382,854	172,517	(131,196)	424,175
Stockholders equity:				
Preferred stock		3	(3)	
Common stock	40	98	(98)	40
Additional paid-in capital	505,235	84,900	(84,900)	505,235
Treasury stock	(11,361)			(11,361)
Retained earnings (accumulated deficit)	(2,869)	6,767	(6,767)	(2,869)
Total stockholders equity	491,045	91,768	(91,768)	491,045
	873,899	264,285	(222,964)	915,220

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Supplemental Condensed Consolidating Statement of Operations

Three Months Ended June 30, 2012

	Parent Company Only	Guarantor Subsidiaries	Eliminations	Consolidated
		(In thousands)		
Revenue:				
Oil and natural gas	$ 70,307	$ 28,942	$	$ 99,249
Other	3,752	19	(3,750)	21
	74,059	28,961	(3,750)	99,270
Costs and expenses:				
Lease operating expenses	13,953	4,708		18,661
Taxes, other than on earnings	250	2,654		2,904
Exploration expenditures, dry hole costs and impairments	5,960	21		5,981
Depreciation, depletion, amortization and accretion	23,672	7,657		31,329
General and administrative	5,537	3,867	(3,750)	5,654
Other expenses	3,540	2		3,542
Total costs and expenses	52,912	18,909	(3,750)	68,071
Income from operations	21,147	10,052		31,199
Other income (expense):				
Interest expense, net	(5,043)			(5,043)
Gain on derivative instruments	30,305			30,305
Income from equity investments	6,303		(6,303)	
Income before income taxes	52,712	10,052	(6,303)	56,461
Income taxes	(17,311)	(3,749)		(21,060)
Net income	$ 35,401	$ 6,303	$ (6,303)	$ 35,401

Supplemental Condensed Consolidating Statement of Operations

Three Months Ended June 30, 2011

	Parent Company Only	Guarantor Subsidiaries	Eliminations	Consolidated
		(In thousands)		
Revenue:				
Oil and natural gas	$ 67,249	$ 25,549	$	$ 92,798
Other	3,751	31	(3,750)	32
	71,000	25,580	(3,750)	92,830
Costs and expenses:				
Lease operating expenses	12,460	5,448		17,908
Taxes, other than on earnings	231	3,464		3,695
Exploration expenditures, dry hole costs and impairments	3,631	77		3,708
Depreciation, depletion, amortization and accretion	22,471	6,855		29,326
General and administrative	4,688	3,858	(3,750)	4,796
Other expenses	2,139	(1)		2,138
Total costs and expenses	45,620	19,701	(3,750)	61,571
Income from operations	25,380	5,879		31,259
Other income (expense):				
Interest expense, net	(4,957)			(4,957)
Gain (loss) on derivative instruments	13,831			13,831
Income from equity investments	3,663		(3,663)	
Income (loss) before income taxes	37,917	5,879	(3,663)	40,133
Income taxes	(12,914)	(2,216)		(15,130)
Net income	$ 25,003	$ 3,663	$ (3,663)	$ 25,003

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Supplemental Condensed Consolidating Statement of Operations

Six Months Ended June 30, 2012

	Parent Company Only	Guarantors	Eliminations	Consolidated
		(In thousands)		
Revenue:				
Oil and natural gas	$ 139,582	$ 58,439	$	$ 198,021
Other	7,504	41	(7,500)	45
	147,086	58,480	(7,500)	198,066
Costs and expenses:				
Lease operating expenses	27,900	9,172		37,072
Taxes, other than on earnings	494	6,151		6,645
Exploration expenditures, dry hole cost and impairments	22,585	19		22,604
Depreciation, depletion, amortization and accretion	44,886	13,499		58,385
General and administrative	10,766	7,732	(7,500)	10,998
Other expenses	3,865	3		3,868
Total costs and expenses	110,496	36,576	(7,500)	139,572
Income from operations	36,590	21,904		58,494
Other income (expense):				
Interest expense, net	(9,879)			(9,879)
Gain (loss) on derivative instruments	10,243			10,243
Income from equity investments	13,734		(13,734)	
Income before income taxes	50,688	21,904	(13,734)	58,858
Deferred income tax expense	(13,784)	(8,170)		(21,954)
Net income	$ 36,904	$ 13,734	$ (13,734)	$ 36,904

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Supplemental Condensed Consolidating Statement of Operations

Six Months Ended June 30, 2011

	Parent Company Only	Guarantors	Eliminations	Consolidated
	(In thousands)			
Revenue:				
Oil and natural gas	$ 113,812	$ 46,201	$	$ 160,013
Other	7,504	62	(7,500)	66
	121,316	46,263	(7,500)	160,079
Costs and expenses:				
Lease operating expenses	23,491	9,748		33,239
Taxes, other than on earnings	596	6,417		7,013
Exploration expenditures, dry hole cost and impairments	14,839	205		15,044
Depreciation, depletion, amortization and accretion	40,719	13,245		53,964
General and administrative	9,863	7,720	(7,500)	10,083
Other expenses	2,393	10		2,403
Total costs and expenses	91,901	37,345	(7,500)	121,746
Income from operations	29,415	8,918		38,333
Other income (expense):				
Interest expense, net	(7,417)			(7,417)
Loss on derivative instruments	(11,694)			(11,694)
Loss on early extinguishment of debt	(2,377)			(2,377)
Income from equity investments	5,556		(5,556)	
Income before income taxes	13,483	8,918	(5,556)	16,845
Deferred income tax expense	(2,989)	(3,362)		(6,351)
Net income	$ 10,494	$ 5,556	$ (5,556)	$ 10,494

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Supplemental Condensed Consolidating Statement of Cash Flows

Six Months Ended June 30, 2012

	Parent Company Only	Guarantor Subsidiaries	Eliminations	Consolidated
		(In thousands)		
Net cash provided by operating activities	$ 97,225	$ 10,958	$	$ 108,183
Cash flows provided by (used in) investing activities:				
Property acquisitions	(33,064)			(33,064)
Exploration and development expenditures	(74,175)	(10,958)		(85,133)
Other property and equipment additions	(1,145)			(1,145)
Net cash used in investing activities	(108,384)	(10,958)		(119,342)
Cash flows provided by (used in) financing activities:				
Deferred financing costs	(6)			(6)
Purchase of shares into treasury	(8,183)			(8,183)
Exercise of stock options and warrants	67			67
Net cash used in financing activities	(8,122)			(8,122)
Net increase in cash and cash equivalents	(19,281)			(19,281)
Cash and cash equivalents at the beginning of the period	80,128			80,128
Cash and cash equivalents at the end of the period	$ 60,847	$	$	$ 60,847

Supplemental Condensed Consolidating Statement of Cash Flows

Six Months Ended June 30, 2011

	Parent Company Only	Guarantor Subsidiaries	Eliminations	Consolidated
		(In thousands)		
Net cash provided by operating activities	$ 51,446	$ 10,743	$	$ 62,189
Cash flows provided by (used in) investing activities:				
Property acquisitions	(196,350)			(196,350)
Exploration and development expenditures	(12,251)	(10,743)		(22,994)
Other property and equipment additions	(361)			(361)
Decrease in restricted cash	2,467			2,467
Net cash used in investing activities	(206,495)	(10,743)		(217,238)
Cash flows provided by (used in) financing activities:				
Proceeds from long-term debt	203,794			203,794
Deferred financing costs	(6,189)			(6,189)
Exercise of stock options	119			119
Net cash provided by financing activities	197,724			197,724
Net increase in cash and cash equivalents	42,675			42,675
Cash and cash equivalents at the beginning of the period	33,553			33,553

Cash and cash equivalents at the end of the period	$	76,228	$		$		$	76,228

Item 2. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS.

Statements we make in this Quarterly Report on Form 10-Q (the Quarterly Report) which express a belief, expectation or intention, as well as those that are not historical fact, may constitute forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. Our forward-looking statements are subject to various risks, uncertainties and assumptions, including those to which we refer under the headings Cautionary Statement Concerning Forward-Looking Statements and Risk Factors in Items 1 and 1A of Part 1 of our 2011 Annual Report and under the heading Risk Factors in Item 1A of Part II of this Quarterly Report.

OVERVIEW

We were incorporated as a Delaware corporation in January 1998 and operate in a single segment as an independent oil and natural gas exploration and production company. Our current operations are concentrated in the U.S. Gulf of Mexico shelf focusing on state and federal waters offshore Louisiana, which we consider our core area. We have focused on acquiring and developing assets in the Gulf of Mexico and the Gulf Coast region, as it offers a balanced and expansive array of existing and prospective exploration, exploitation and development opportunities in both established productive horizons and deeper geologic formations.

We maintain a website at *www.eplweb.com* that contains information about us, including links to our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and all related amendments as soon as reasonably practicable after providing such reports to the Securities and Exchange Commission (the SEC).

We use the successful efforts method of accounting for oil and natural gas producing activities. Under this method, we capitalize lease acquisition costs, costs to drill and complete exploration wells in which proven reserves are discovered and costs to drill and complete development wells. Exploratory drilling costs are charged to expense if and when activities result in no reserves in commercial quantities. Seismic, geological and geophysical, and delay rental expenditures are expensed as they are incurred. We conduct various exploration and development activities jointly with others and, accordingly, recorded amounts for our oil and natural gas properties reflect only our proportionate interest in such activities. Our 2011 Annual Report includes a discussion of our critical accounting policies, which have not changed significantly since the end of the last fiscal year.

We produce both oil and natural gas. Throughout this Quarterly Report, when we refer to total production, total reserves, percentage of production, percentage of reserves, or any similar term, we have converted our natural gas reserves or production into barrel of oil equivalents. For this purpose, six thousand cubic feet of natural gas is equal to one barrel of oil, which is based on the relative energy content of natural gas and oil. Natural gas liquids are aggregated with oil in this Quarterly Report.

Recent Developments

On May 15, 2012, we acquired from W&T Offshore, Inc. (W&T) an asset package consisting of certain shallow-water Gulf of Mexico shelf oil and natural gas interests in our South Timbalier 41 field (ST 41 Interests) located in the Gulf of Mexico for $32.4 million in cash, subject to customary adjustments to reflect an economic effective date of April 1, 2012 (the ST 41 Acquisition). We estimate that the proved reserves as of the April 1, 2012 economic effective date totaled approximately 1.0 Mmboe, of which 51% were oil and 84% were proved developed reserves. Prior to the acquisition, we owned a 60% working interest in the properties and W&T owned a 40% working interest. As a result of the acquisition, we have become the sole working interest owner of the South Timbalier 41 field. We funded the ST 41 Acquisition with cash on hand.

On June 20, 2012, we were the high bidder on six leases at the Central Gulf of Mexico Lease Sale 216/222. The six high bid lease blocks cover a total of 27,148 acres on a gross and net basis and are all located in the shallow Gulf of Mexico shelf within our core area of operations. Our share of the high bids totaled $7 million.

Overview and Outlook

Our fiscal year 2012 capital budget is $217 million, of which $126 million is allocated to development activities, $84 million to exploration projects, including seismic purchases, within existing core field areas and $7 million to the recently bid leases in the shallow Gulf of Mexico shelf. We recently acquired additional 2-D and 3-D seismic data sets regionally across our current offshore operating areas and extending onshore Louisiana where the geology is characterized by the same productive horizons and structural features. Additionally, we plan to spend approximately $33 million in 2012 on plugging, abandonment and other decommissioning activities.

We allocate capital in a rigorous and disciplined manner intended to achieve an overall lower risk capital expenditure profile that focuses on maximizing rate of return and requires projects to compete on that basis. This allocation has led us to focus on oil-weighted projects, which has resulted in a trend of increasing oil production volumes and declining natural gas production volumes.

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We continually review and monitor opportunities to acquire producing properties, leasehold acreage and drilling prospects so that we can act quickly as acquisition opportunities become available. We intend to focus our acquisition strategy on assets in the Gulf of Mexico and the Gulf Coast region that are characterized by production-weighted reserves, seismic coverage, operated positions and the ability to consolidate interests in existing properties. We intend to use acquisitions of this type as a key method to replace and grow reserves and production, because we believe this strategy increases production and cash flow while reducing dry hole and exploration risk. We believe our expertise in the Gulf of Mexico shelf and in plugging and abandonment operations allows us to effectively evaluate acquisitions and to operate any properties we eventually acquire.

We continue to generate prospects, strive to maintain an extensive inventory of drillable prospects in-house and maintain exposure to new opportunities through relationships with industry partners. Generally, we fund any exploration and development expenditures with internally generated cash flows.

Our longer term operating strategy is to increase our oil and natural gas reserves and production while focusing on reducing exploration and development costs and operating costs to remain competitive with our offshore Gulf of Mexico industry peers.

We are also focused on the development of a core competency in plugging, abandonment and decommissioning operations, which will enable us to achieve our objectives of prudently removing idle infrastructure throughout the remaining productive lives of our fields and, over time, to reduce ongoing lease operating expenses (LOE) associated with maintaining idle infrastructure.

Our revenue, profitability and future growth rate depend substantially on factors beyond our control, such as oil and natural gas prices, tropical weather, economic, political and regulatory developments and availability of other sources of energy. Oil and natural gas prices historically have been volatile and may fluctuate widely in the future. Sustained periods of low prices for oil and natural gas could have a material adverse effect on our financial position, our results of operations, our cash flows, the quantities of oil and natural gas reserves that we can economically produce and our access to capital. See Risk Factors in Item 1A of our 2011 Annual Report and Item 1A of Part II of this Quarterly Report for a more detailed discussion of these risks.

Results of Operations

Three Months Ended June 30, 2012

During the three months ended June 30, 2012, we completed two (2) development drilling operations both of which were successful, and three (3) recompletion operations, all of which were successful. We also completed one (1) exploratory drilling operation, which was successful in a development zone.

Our operating results for the three months ended June 30, 2012, compared to the three months ended June 30, 2011, reflect an 18% increase in oil production, partially offset by lower natural gas production and lower average selling prices for our oil and natural gas. Our product mix for the three months ended June 30, 2012 was 78% oil (including natural gas liquids) compared to 74% for the three months ended June 30, 2011. Production from the acquired Main Pass Interests and ST41 Interests had an impact of approximately 785 Boe per day on the production rate in the three months ended June 30, 2012, compared to results for the three months ended June 30, 2011, which do not include production from the Main Pass Interests and ST41 Interests. We expect our full-year 2012 oil production to increase as compared to our full-year 2011 oil production.

For the three months ended June 30, 2012, our revenues increased 7% as compared to the three months ended June 30, 2011, due primarily to the 18% increase in oil production. Our overall production volumes increased by 12% for the three months ended June 30, 2012 when compared to the three months ended June 30, 2011. Our Gulf of Mexico shelf production increased 20% in the three months ended June 30, 2012, as compared to the three months ended June 30, 2011, due primarily to production increases in our West Delta field, partially offset by production declines in our predominantly natural gas fields. In addition, our deepwater production, primarily natural gas, was curtailed during the three months ended June 30, 2012 due to third party downstream facility modifications.

In addition to the items addressed above, our net income for the three months ended June 30, 2012 includes a net gain on derivative instruments of $30.3 million as compared to a net gain of $13.8 million for the three months ended June 30, 2011.

Our effective income tax rate for the three months ended June 30, 2012 was 37.3%. Our effective income tax rate for the three months ended June 30, 2011 was 37.7%. The decrease in our effective income tax rate is primarily related to estimated state income taxes.

Six Months Ended June 30, 2012

During the six months ended June 30, 2012, we completed five (5) development drilling operations, all of which were successful, and twelve (12) recompletion operations, ten (10) of which were successful. We also completed three (3) exploratory drilling operations, one of which was successful in a development zone.

Our operating results for the six months ended June 30, 2012, compared to the six months ended June 30, 2011, reflect a 29% increase in oil production and higher average selling prices for our oil, partially offset by lower natural gas production and lower

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average selling prices for our natural gas. Our product mix for the six months ended June 30, 2012 was 78% oil (including natural gas liquids) compared to 69% for the six months ended June 30, 2011. Production from the acquired ASOP Properties, Main Pass Interests and ST41 Interests had an impact of approximately 4,741 Boe per day on the production rate in the six months ended June 30, 2012, compared to results for the six months ended June 30, 2011, which include production from the ASOP Properties for the period from February 14, 2011 to June 30, 2011, reflecting only a 2,686 Boe per day impact on the production rate in the prior period. We expect our full-year 2012 oil production to increase as compared to our full-year 2011 oil production.

For the six months ended June 30, 2012, our revenues increased 24% as compared to the six months ended June 30, 2011, due primarily to the 29% increase in oil production and higher oil sales prices. Our overall production volumes increased by 13% for the six months ended June 30, 2012 when compared to the six months ended June 30, 2011. Our Gulf of Mexico shelf production increased 23% in the six months ended June 30, 2012, as compared to the six months ended June 30, 2011, due primarily to production increases in our West Delta field and production from the ASOP Properties, Main Pass Interests and ST41 Interests, partially offset by production declines in our predominantly natural gas fields. In addition, our deepwater production, primarily natural gas, was curtailed during the six months ended June 30, 2012 due to third party downstream facility modifications.

In addition to the items addressed above, our net income for the six months ended June 30, 2012 includes significant exploration expenditures, primarily due to the area-wide 2-D and 3-D seismic purchases totaling $10.5 million, impairments of $5.7 million and a net gain on derivative instruments of $10.2 million. The net income for the six months ended June 30, 2011 reflects impairments of $13.7 million, a net loss on derivative instruments of $11.7 million and a $2.4 million loss on early extinguishment of debt as a result of the termination of our prior credit facility.

Our effective income tax rate for the six months ended June 30, 2012 was 37.3%. Our effective income tax rate for the six months ended June 30, 2011 was 37.7%. The decrease in our effective income tax rate is primarily related to estimated state income taxes. Our state income taxes primarily relate to income apportioned to Louisiana. Our estimated Louisiana income apportionment factor can change as our production mix changes and commodity prices fluctuate. Further, our estimated Louisiana income apportionment factor can impact our estimated utilization of our net operating losses. We expect that changes in these estimates will continue to result in changes in our effective income tax rate.

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RESULTS OF OPERATIONS

The following table presents information about our oil and natural gas operations.

	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
Net production (per day):				
Oil (Bbls)	9,768	8,286	9,577	7,431
Natural gas (Mcf)	16,658	17,383	15,804	20,174
Total (Boe)	12,544	11,183	12,211	10,793
Average sales prices:				
Oil (per Bbl)	$ 107.75	$ 113.14	$ 109.68	$ 106.98
Natural gas (per Mcf)	2.29	4.74	2.38	4.41
Total (per Boe)	86.94	91.19	89.10	81.90
Oil and natural gas revenues (in thousands):				
Oil	$ 95,779	$ 85,307	$ 191,176	$ 143,892
Natural gas	3,470	7,491	6,845	16,121
Total	99,249	92,798	198,021	160,013
Impact of derivatives instruments settled during the period [1]:				
Oil (per Bbl)	$ (0.23)	$ (12.55)	$ (2.14)	$ (10.97)
Natural gas (per Mcf)	0.01			
Average costs (per Boe):				
LOE	$ 16.35	$ 17.60	$ 16.68	$ 17.01
Depreciation, depletion and amortization (DD&A)	24.46	25.08	23.32	23.85
Accretion of liability for asset retirement obligations	2.99	3.74	2.95	3.78
Taxes, other than on earnings	2.54	3.63	2.99	3.59
General and administrative (G&A) expenses	4.95	4.71	4.95	5.16
Increase (decrease) in oil and natural gas revenues due to:				
Changes in prices of oil	$ (4,066)		$ 3,631	
Changes in production volumes of oil	14,538		43,653	
Total increase in oil sales	10,472		47,284	
Changes in prices of natural gas	$ (3,870)		$ (7,427)	
Changes in production volumes of natural gas	(151)		(1,849)	
Total decrease in natural gas sales	(4,021)		(9,276)	

(1) See Other Income and Expense section for further discussion of the impact of derivative instruments.

Three Months Ended June 30, 2012 Compared to Three Months Ended June 30, 2011

Revenue and Net Income

	Three Months Ended June 30 2012	Three Months Ended June 30 2011	$ Change	% Change
Oil and natural gas revenues	$ 99,249	$ 92,798	$ 6,451	7%
Net income	35,401	25,003	10,398	NM

NM Not Meaningful

Our oil and natural gas revenues increased primarily as a result of the 18% increase in oil production in the three months ended June 30, 2012, as compared to the three months ended June 30, 2011, offset in part by a 5% decline in average selling prices for our oil, a 4% decline in natural gas production and a 52% decline in average selling prices for our natural gas in the three months ended June 30, 2012 as compared to the three months ended June 30, 2011. Oil represented 78% of total production for the three months ended June 30, 2012 as compared to 74% of total production for the three months ended June 30, 2011.

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Operating Expenses

Our operating expenses primarily consist of the following:

	Three Months Ended June 30, 2012	2011	$ Change	% Change
	(in thousands)			
LOE	$ 18,661	$ 17,908	$ 753	4%
Exploration expenditures and dry hole costs	2,587	822	1,765	NM
Impairments	3,394	2,886	508	NM
DD&A, including accretion expense	31,329	29,326	2,003	7%
G&A expenses	5,654	4,796	858	18%
Taxes, other than on earnings	2,904	3,695	(791)	(21)%

NM Not Meaningful

LOE increased for the three months ended June 30, 2012, as compared to the three months ended June 30, 2011, primarily due to the 2011 acquisitions of the Main Pass Interests and ST41 Interests.

During the three months ended June 30, 2012, we recorded approximately $1.5 million of dry hole costs, primarily associated with an unsuccessful exploratory portion of a well that was successfully completed in a development zone. In addition, exploration expenditures during the three months ended June 30, 2012 include $0.2 million of seismic expense.

Impairments for the three months ended June 30, 2012 were primarily due to the decline in our estimate of future natural gas prices, which affected one of our natural gas producing fields, and reservoir performance at another natural gas producing field. These fields were determined to have future net cash flows less than their carrying values resulting in the write down of these properties to their estimated fair values at June 30, 2012. Impairments for the three months ended June 30, 2011 were primarily related to reservoir performance at two of our natural gas producing fields.

G&A expenses include non-cash share-based compensation of $1.3 million and $0.8 million in the three months ended June 30, 2012 and 2011, respectively.

Taxes, other than on earnings, were lower in the three months ended June 30, 2012, as compared to the three months ended June 30, 2011. The decrease is primarily related to severance taxes.

Other Income and Expense

For the three months ended June 30, 2012 and 2011, our interest expense consists primarily of interest on our 8.25% Notes issued in connection with the ASOP Acquisition on February 14, 2011.

Other income (expense) in the three months ended June 30, 2012 includes a net gain on derivative instruments of $30.3 million consisting of an unrealized gain of $30.5 million due to the change in fair market value of derivative instruments which were to be settled in the future primarily from the impact of lower oil prices during 2012 and a realized loss of $0.2 million on derivative instruments settled during the quarter. Other income (expense) in the three months ended June 30, 2011 includes a net gain of $13.8 million consisting of an unrealized gain of $23.3 million due to the change in fair market value of derivative instruments and a loss of $9.5 million on derivative instruments settled during the quarter primarily from the impact of our oil fixed-price swaps.

Six Months Ended June 30, 2012 Compared to Six Months Ended June 30, 2011

Revenue and Net Income

	Six Months Ended June 30, 2012	2011		
	(in thousands)		$ Change	% Change
Oil and natural gas revenues	$ 198,021	$ 160,013	$ 38,008	24%
Net income	36,904	10,494	26,410	NM

NM Not Meaningful

Our oil and natural gas revenues increased primarily as a result of the 29% increase in oil production and the 3% increase in average selling prices for our oil production in the six months ended June 30, 2012, as compared to the six months ended June 30,

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2011, offset in part by a 22% decline in natural gas production and a 46% decline in average selling prices for our natural gas in the six months ended June 30, 2012 as compared to the six months ended June 30, 2011. Oil represented 78% of total production for the six months ended June 30, 2012 as compared to 69% of total production for the six months ended June 30, 2011.

Operating Expenses

Our operating expenses primarily consist of the following:

	Six Months Ended June 30, 2012	2011	$ Change	% Change
	(in thousands)			
LOE	$ 37,072	$ 33,239	$ 3,833	12%
Exploration expenditures and dry hole costs	16,896	1,370	15,526	NM
Impairments	5,708	13,674	(7,966)	NM
DD&A, including accretion expense	58,385	53,964	4,421	8%
G&A expenses	10,998	10,083	915	9%
Taxes, other than on earnings	6,645	7,013	(368)	(5%)

LOE increased for the six months ended June 30, 2012, as compared to the six months ended June 30, 2011, primarily due to the 2011 acquisitions of the ASOP Properties and Main Pass Interests and the 2012 acquisition of the ST41 Interests.

During the six months ended June 30, 2012, we recorded approximately $4.2 million of dry hole costs, primarily associated with two exploratory wells which reached their target depths in January 2012 and were determined to be unsuccessful and an unsuccessful exploratory portion of a well that was successfully completed in a development zone drilled in June 2012. In addition, exploration expenditures during the six months ended June 30, 2012 include $10.5 million of seismic expense.

Impairments for the six months ended June 30, 2012 were primarily due to the decline in our estimate of future natural gas prices, which affected two of our natural gas producing fields and reservoir performance at one of those fields. These fields were determined to have future net cash flows less than their carrying values resulting in the write downs of these properties to their estimated fair values. Impairments for the six months ended June 30, 2011 were primarily related to reservoir performance at one of our natural gas producing fields, which was determined to have future net cash flows less than its carrying value resulting in the write down of this property to its estimated fair value.

G&A expenses include non-cash share-based compensation of $2.3 million and $1.3 million in the six months ended June 30, 2012 and 2011, respectively. G&A expenses in the six months ended June 30, 2011 also include $0.5 million in acquisition costs related to the ASOP Acquisition.

Taxes, other than on earnings, were lower in the six months ended June 30, 2012, as compared to the six months ended June 30, 2011. The decrease is primarily related to severance taxes.

Other Income and Expense

For the six months ended June 30, 2012 and 2011, our interest expense consists primarily of interest on our 8.25% Notes issued in connection with the ASOP Acquisition on February 14, 2011.

Other income (expense) in the six months ended June 30, 2012 includes a net gain on derivative instruments of $10.2 million consisting of an unrealized gain of $13.9 million due to the change in fair market value of derivative instruments which were to be settled in the future and a realized loss of $3.7 million on derivative instruments settled during the quarter primarily from the impact of higher oil prices during 2012. Other income (expense) in the six months ended June 30, 2011 includes a net loss of $11.7 million consisting of an unrealized gain of $3.1 million due to the change in fair market value of derivative instruments and a loss of $14.8 million on derivative instruments settled during the period primarily from the impact of our oil fixed-price swaps.

LIQUIDITY AND CAPITAL RESOURCES

Liquidity and Capital Resources

At June 30, 2012, we had unrestricted cash on hand of approximately $60.8 million and no amounts drawn under our credit facility, which currently has a borrowing base of $200 million. Our fiscal year 2012 capital budget is $217 million, of which $126 million is allocated to development activities, $84 million to exploration projects within existing core field areas including seismic purchases and $7 million to the recently bid leases in the shallow Gulf of Mexico shelf. Additionally, we plan to spend approximately $33 million in 2012 on plugging, abandonment and other decommissioning activities. We intend to finance our capital expenditure budget and plugging and abandonment expenditures with cash flow from operations.

Sources and Uses of Capital

As of June 30, 2012, we had cash and cash equivalents of $60.8 million and no amounts drawn under our Senior Credit Facility (described below). At the closing of our 8.25% Notes offering on February 14, 2011, our prior credit facility was replaced with our Senior Credit Facility, which had an initial borrowing base of $150.0 million and was increased to $200.0 million in November 2011.

Capital Expenditures. During the six months ended June 30, 2012, we incurred costs of approximately $110.2 million on development and exploration activities, including $10.5 million on the seismic purchases previously described. We also spent approximately $19.3 million on plugging, abandonment and other decommissioning activities during the six months ended June 30, 2012.

Acquisitions. On May 15, 2012, we acquired the remaining 40% working interest in our South Timbalier 41 field for $32.4 million in cash, subject to customary adjustments to reflect an economic effective date of April 1, 2012. We funded the ST 41 acquisition with cash on hand. We may fund future acquisitions with a combination of cash on hand, borrowings on our credit facility and issuances of one or more debt and equity securities under our universal shelf registration statement that became effective under the Securities Act of 1933 in July 2011.

Share Repurchase Program. In August 2011, the Board of Directors authorized a program for the repurchase of our outstanding common stock for up to an aggregate cash purchase price of $20.0 million and increased the program to $40.0 million in May 2012. Under the program, we have repurchased 1,429,800 shares at an aggregate cash purchase price of approximately $19.5 million, including 410,800 shares purchased for approximately $6.7 million during 2012. Such shares are held in treasury and could be used to provide available shares for possible resale in future public or private offerings and our employee benefit plans. The repurchases have been, and will be, carried out in accordance with certain volume, timing and price constraints imposed by the SEC s rules applicable to such transactions. The amount, timing and price of purchases otherwise depend on market conditions and other factors.

Working Capital. At June 30, 2012, we had a working capital deficit of $30.6 million, compared to working capital of $10.2 million at December 31, 2011. We have experienced, and may experience in the future, working capital deficits. Our working capital deficits have historically resulted from increased accounts payable and accrued expenses related to ongoing exploration and development costs, which may be capitalized as noncurrent assets.

Restricted Cash. We maintain restricted escrow funds in a trust for future plugging, abandonment and other decommissioning costs at our East Bay field. The trust was originally funded with $15.0 million and, with accumulated interest, had increased to $16.7 million at December 31, 2008. We have made draws to date of $10.7 million. We were able to draw from the trust upon the authorization, and subsequent completion, of qualifying abandonment activities at our East Bay field. As of the date of this Quarterly Report, we had $6.0 million remaining in restricted escrow funds for decommissioning work in our East Bay field, which will remain restricted until substantially all required decommissioning in the East Bay field is complete. Amounts on deposit in the trust account are reflected in Restricted cash on our condensed consolidated balance sheets.

The Bureau of Ocean Energy Management (BOEM), the Bureau of Safety and Environmental Enforcement (BSEE) and other regulatory bodies, including those regulating the decommissioning of our pipelines and facilities under the jurisdiction of the state of Louisiana, may change their requirements or enforce requirements in a manner inconsistent with our expectations, which could materially increase the cost of such activities and/or accelerate the timing of cash expenditures and could have a material adverse effect on our financial position, results of operations and cash flows. For important additional information regarding risks related to our regulatory environment, see Risk Factors in Part II, Item 1A of this Quarterly Report and in Part I, Item 1A of our 2011 Annual Report.

8.25% Notes. On February 14, 2011, we issued $210 million in aggregate principal amount of the 8.25% Notes. We used the net proceeds from the offering of the 8.25% Notes of $202 million, after deducting the initial purchasers discount and estimated offering expenses payable by us, to acquire the ASOP Properties for a purchase price of $200.7 million, before adjustments to reflect an economic effective date of January 1, 2011, and for general corporate purposes. The 8.25% Notes bear interest from the date of their issuance at an annual rate of 8.25% with interest on outstanding notes payable semi-annually, in arrears, on February 15 and August 15 of each year, commencing on August 15, 2011. The 8.25% Notes are fully and unconditionally guaranteed, jointly and severally, on an unsecured senior basis initially by each of our existing direct and indirect domestic subsidiaries (other than immaterial subsidiaries). The 8.25% Notes will mature on February 15, 2018. For more information on our 8.25% Notes, see Note 7, Indebtedness, of our consolidated financial statements contained in Part II, Item 8 of our 2011 Annual Report.

Senior Credit Facility. On February 14, 2011, we entered our Senior Credit Facility with BMO Capital Markets, as lead arranger, Bank of Montreal, as administrative agent and a lender, and the other lenders party thereto. The terms of our Senior Credit Facility established a revolving credit facility with a four-year term that may be used for revolving credit loans and letters of credit up to an aggregate principal amount of $250 million. The maximum amount of the letters of credit that may be outstanding at any one time is $20 million. The amount available under the revolving credit facility is limited by the borrowing base. With the consent of the agent, we also have the ability to increase the aggregate commitments under the Senior Credit Facility by up to an additional $50 million to the extent that existing and/or future lenders provide additional commitments. The Senior Credit Facility is secured by substantially all of our assets, including mortgages on at least 85% of our oil and gas properties and the stock of certain wholly-owned subsidiaries. The borrowing base under our Senior Credit Facility has been determined at the discretion of the lenders, based on the collateral value of our proved reserves, and is subject to potential special and regular semi-annual redeterminations. As of May 1, 2012, we completed our semi-annual redetermination and our borrowing base remains at $200 million. Borrowings under our Senior Credit Facility bear interest ranging from a base rate plus a margin of 1.00% to 2.00% on base rate borrowings and LIBOR plus a margin of 2.00% to 3.00% on LIBOR borrowings. We had no amounts drawn under our Senior Credit Facility at June 30, 2012 and December 31, 2011.

Terminated Credit Facility. We terminated the then existing prior credit facility in connection with entering into our current credit facility described above, resulting in a loss on early extinguishment of debt of $2.4 million, primarily due to writing off the unamortized deferred financing costs associated with the terminated facility.

Analysis of Cash Flows Six Months Ended June 30, 2012

The following table sets forth our cash flows (in thousands):

	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
Cash flows from operating activities	$ 108,183	$ 62,189
Cash flows used in investing activities	(119,342)	(217,238)
Cash flows provided by (used in) financing activities	(8,122)	197,724

The increase in our 2012 cash flows from operating activities primarily reflects increases in revenues due to the increase in our oil production and oil prices, partially offset by decreases in natural gas revenues during the six months ended June 30, 2012, as compared to the six months ended June 30, 2011.

Net cash used in investing activities was lower in the six months ended June 30, 2012, as compared to the six months ended June 30, 2011, due to our acquisition of the ASOP Properties during the six months ended June 30, 2011. However, our exploration and development expenditures were higher in the six months ended June 30, 2012, due to our higher 2012 capital expenditures budget. In addition, we acquired the ST41 Interests in the six months ended June 30, 2012.

Net cash used in financing activities during the six months ended June 30, 2012 reflects the settlements of purchases of shares of our common stock (which have been kept as treasury shares) pursuant to our repurchase program during the six months ended June 30, 2012. Net cash provided by financing activities during the six months ended June 30, 2011 reflects $203.8 million of net cash proceeds (before offering expenses of $1.8 million) from the issuance of the 8.25% Notes, partially offset by expenditures of $6.2 million for financing costs primarily associated with our Senior Credit Facility and the offering expenses associated with our 8.25% Notes.

We have not paid any cash dividends in the past on our common stock. The covenants in certain debt instruments to which we are a party, including our Senior Credit Facility and the Indenture governing the 8.25% Notes, place certain restrictions and conditions on our ability to pay dividends. Any future cash dividends would depend on contractual limitations, future earnings, capital requirements, our financial condition and other factors determined by our board of directors.

New Accounting Pronouncements

See Note 9 of the condensed consolidated financial statements in Item 1, Part 1 of this Quarterly Report.

Cautionary Statement Concerning Forward Looking Statements

This Quarterly Report contains forward-looking statements within the meaning of, and we intend that such forward-looking statements be subject to the safe harbor provisions of, the U.S. federal securities laws. Forward-looking statements are, by definition, statements that are not historical in nature and relate to possible future events. They may be, but are not necessarily, identified by words such as will, would, should, likely, estimates, thinks, strives, may, anticipates, expects, believes, intends, goals, plans, or projects and similar expres

These forward-looking statements reflect our current views with respect to possible future events, are based on various assumptions and are subject to risks and uncertainties. These forward-looking statements are not guarantees or predictions of our future performance, and our actual results and future developments may differ materially from those projected in, and contemplated by, the forward-looking statements. As a result, you should not place undue reliance on these forward-looking statements. Our actual results could differ materially from those anticipated in these forward-looking statements. Among the factors that could cause actual results to differ materially are the risks and uncertainties described under, Risk Factors in Item 1A of Part I of our 2011 Annual Report and Item 1A of Part II of this Quarterly Report, including the following:

planned and unplanned capital expenditures;

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adequacy of capital resources and liquidity including, but not limited to, access to additional capacity under our credit facility;

our substantial level of indebtedness;

our ability to incur additional indebtedness;

volatility in oil and natural gas prices;

volatility in the financial and credit markets;

changes in general economic conditions;

uncertainties in reserve and production estimates;

replacing our oil and natural gas reserves;

unanticipated recovery or production problems;

availability, cost and adequacy of insurance coverage;

hurricane and other weather-related interference with business operations;

drilling and operating risks;

production expense estimates;

the impact of derivative positions;

our ability to retain and motivate key executives and other necessary personnel;

availability of drilling and production equipment and field service providers;

the effects of delays in completion of, or shut-ins of, gas gathering systems, pipelines and processing facilities;

- potential costs associated with complying with new or modified regulations promulgated by the BOEM and BSEE;
- the impact of political and regulatory developments;
- risks and liabilities associated with acquired properties or businesses;
- our ability to make and integrate acquisitions;
- oil and gas prices and competition; and
- our ability to generate sufficient cash flow to meet our debt service and other obligations.

Many of these factors are beyond our ability to control or predict. Any, or a combination, of these factors could materially affect our future financial condition or results of operations and the ultimate accuracy of the forward-looking statements. These forward-looking statements are not guarantees of our future performance, and our actual results and future developments may differ materially from those projected in the forward-looking statements. Management cautions against putting undue reliance on forward-looking statements or projecting any future results based on such statements.

For a further list and description of various risks, relevant factors and uncertainties that could cause future results or events to differ materially from those expressed or implied in our forward-looking statements, see Risk Factors in Part 1, Item 1A of our 2011 Annual Report and elsewhere in our 2011 Annual Report and Part II, Item 1A of this Quarterly Report and elsewhere in this Quarterly Report; our reports and registration statements filed from time to time with the SEC; and other announcements we make from time to time. Given these risks and uncertainties, you should not place undue reliance on these forward-looking statements.

Although we believe that the assumptions on which any forward-looking statements are based in this Quarterly Report and other periodic reports filed by us are reasonable when and as made, no assurance can be given that such assumptions will prove correct. All forward-looking statements in this Quarterly Report are expressly qualified in their entirety by the cautionary statements in this section and elsewhere in this Quarterly Report and we undertake no obligation to publicly update or revise any forward-looking statements, except as required by applicable securities laws and regulations.

Item 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risks. The term market risk refers to the risk of loss arising from adverse changes in oil and gas prices and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. This forward-looking information provides indicators of how we view our ongoing market-risk exposure.

Interest Rate Risk

We are exposed to changes in interest rates which affect the interest earned on our interest-bearing deposits and the interest paid on borrowings under our Senior Credit Facility. Currently, we do not use interest rate derivative instruments to manage exposure to interest rate changes. Borrowings under our Senior Credit Facility bear interest ranging from a base rate plus a margin of 1.00% to 2.00% on base rate borrowings and LIBOR plus a margin of 2.00% to 3.00% on LIBOR borrowings. We had no amounts drawn under our Senior Credit Facility at June 30, 2012 or December 31, 2011. At June 30, 2012, our total indebtedness outstanding consisted of $204.8 million (net of unamortized original purchaser s discount of $5.2 million) related to our fixed-rate 8.25% Notes, which mature on February 15, 2018. The estimated fair value of our 8.25% Notes was approximately $207.9 million at June 30, 2012.

Commodity Price Risk

Our revenues, profitability and future growth depend substantially on prevailing prices for oil and natural gas. Prices also affect the amount of cash flow available for capital expenditures and our ability to borrow and raise additional capital. The amount we can borrow under our Senior Credit Facility is subject to periodic redetermination based in part on changing expectations of future prices. Lower prices may reduce the amount of oil and natural gas that we can economically produce. We currently sell all of our oil and natural gas production under price sensitive or market price contracts.

Historically, we have used commodity derivative instruments to manage commodity price risks associated with future oil and natural gas production. As of June 30, 2012, the following derivative instruments were outstanding:

Oil Contracts

	Fixed-Price Swaps			
Remaining Contract Term	**Daily Average Volume (Bbls)**	**Volume (Bbls)**	**Average Swap Price ($/Bbl)**	**Fair Value (In thousands)**
July 2012	3,394	105,200	$ 99.43	$ 1,033
August 2012 November 2012	2,921	356,400	$ 104.05	$ 3,246
December 2012	3,361	104,200	$ 102.80	$ 899
January 2013 July 2013	3,203	679,000	$ 100.30	$ 5,091
August 2013 November 2013	1,926	235,000	$ 103.69	$ 1,958
December 2013	2,306	71,500	$ 102.05	$ 580

	Collars			
Remaining Contract Term	**Daily Average Volume (Bbls)**	**Volume (Bbls)**	**Strike Price ($/Bbl)**	**Fair Value (In thousands)**
July 2012	1,000	31,000	$ 87.50/123.18	$ 36
August 2012 November 2012	1,000	122,000	$ 87.50/123.18	$ 458
December 2012	1,000	31,000	$ 87.50/123.18	$ 159
January 2013 July 2013	1,500	318,000	$ 83.33/112.53	$ (93)
August 2013 November 2013	1,500	183,000	$ 83.33/112.53	$ (3)
December 2013	1,500	46,500	$ 83.33/112.53	$ 6

Gas Contracts

	Fixed-Price Swaps			
Remaining Contract Term	**Daily Average Volume (Bbls)**	**Volume (Bbls)**	**Average Swap Price ($/Bbl)**	**Fair Value (In thousands)**
July 2012 December 2012	1,000	184,000	$ 2.69	$ (46)
January 2013 December 2013	1,000	365,000	$ 3.51	$ (25)

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Subsequent to June 30, 2012, we entered additional fixed-price oil swap contracts as summarized below:

Contract Term	Daily Average Volume (Bbls)	Average Swap Price ($/Bbl)
January 2013 June 2013	2,000	$ 100.13
July 2013 December 2013	500	$ 94.50

The United States Congress adopted comprehensive financial reform legislation that establishes federal oversight and regulation of the over-the-counter derivatives market and entities that participate in that market. The new regulation, known as the Dodd-Frank Wall Street Reform and Consumer Protection Act required the Commodities Futures Trading Commission (the CFTC) and the SEC to promulgate rules and regulations implementing the new legislation. In July 2012 certain definitions were adopted by the SEC and the CFTC and based on those definitions, we believe we will qualify for the end-user exception related to the clearing requirement for swaps, but we will be required to adhere to new reporting requirements.

Item 4. CONTROLS AND PROCEDURES.

(a) Quarterly Evaluation of Disclosure Controls and Procedures

Disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) are designed to ensure that information required to be disclosed in our reports filed under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms. This information is also accumulated and communicated to management, including our principal executive officer and our principal financial officer, as appropriate, to allow timely decisions regarding required disclosure. Our management, under the supervision and with the participation of our principal executive officer and principal financial officer, evaluated the effectiveness of the design and operation of our disclosure controls and procedures as of the end of the most recent fiscal quarter reported on herein. Based on that evaluation, our principal executive officer and principal financial officer concluded that our disclosure controls and procedures were effective as of June 30, 2012.

Because of their inherent limitations, disclosure controls and procedures may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that such controls and procedures may become inadequate because of changes in conditions, or that the degree of compliance with the controls or procedures may deteriorate. Accordingly, even effective disclosure controls and procedures can provide only reasonable assurance of achieving their control objectives.

(b) Changes in Internal Control Over Financial Reporting

There were no changes in our internal control over financial reporting during the three months ended June 30, 2012 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II OTHER INFORMATION

Item 1. LEGAL PROCEEDINGS.

For information regarding legal proceedings, see the information in Note 8, Commitments and Contingencies in the condensed consolidated financial statements in Part I, Item 1 of this Quarterly Report.

Item 1A. RISK FACTORS.

In addition to the risk factor below and the other information set forth in this Form 10-Q, you should carefully consider the factors discussed in Part I, Item 1A. Risk Factors in our 2011 Annual Report that could materially affect our business, financial condition or future results. The risks described in this Quarterly Report on Form 10-Q and in our 2011 Annual Report are not the only risks facing the Company. Additional risks and uncertainties not currently known to us, or that we currently deem to be immaterial, also may have a material adverse effect on our business, financial condition and future results.

The risk factor below is an update to the risk factor titled We may not be insured against all of the operating risks to which our business is exposed found under Item 1A. Risk Factors in our 2011 Annual Report.

We may not be insured against all of the operating risks to which our business is exposed.

In accordance with industry practice, we maintain insurance coverage against some, but not all, of the operating risks to which our business is exposed. We insure some, but not all, of our properties from operational and hurricane related events. We currently have insurance policies that include coverage for general liability, physical damage to our oil and gas properties, operational control of well, oil pollution, third party liability, workers compensation and employers liability and other coverage. Our insurance coverage includes deductibles that must be met prior to recovery, as well as sub-limits. Additionally, our insurance is subject to exclusions and limitations, and there is no assurance that such coverage will adequately protect us against liability from all potential consequences and damages and losses.

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Currently, we have general liability insurance coverage with an annual aggregate limit of $2.0 million and umbrella/excess liabilities coverage with an aggregate limit of $150.0 million applicable to our working interest. Our general liability policy is subject to a $25,000 per incident deductible. We also have offshore property physical damage and operators extra expense policies that contain an aggregate of $175.7 million of named windstorm limit of which we self-insure approximately 9%. Recoveries from these policies are subject to a $2.5 million deductible that applies to non-named windstorm occurrences and a $20.0 million deductible that applies to named windstorm events except for East Bay central facilities and rental compressor losses, which are subject to a 1.5% deductible. Further, there are scheduled sub-limits within the named windstorm annual aggregate limit for re-drill, non-blowout plugging and abandonment and excess removal of wreck. Our operational control of well coverage provides limits that vary by well location and depth and range from a combined single limit of $20.0 million to $75.0 million per occurrence. Deepwater wells have a coverage limit of $50.0 million per occurrence. Additionally, we maintain $150.0 million in oil pollution liability coverage as required under the Oil Pollution Act of 1990. Our control of well and oil pollution liability policy limits are scaled proportionately to our working interests, except for our deepwater control of well coverage, to which the $50.0 million limit applies to our working interest. Under our service agreements, including drilling contracts, generally we are indemnified for injuries and death of the service provider s employees as well as contractors and subcontractors hired by the service provider.

An operational or hurricane-related event may cause damage or liability in excess of our coverage, which might severely impact our financial position. We may be liable for damages from an event relating to a project in which we are a non-operator, but have a working interest in such project. Such an event may also cause a significant interruption to our business, which might also severely impact our financial position. For example, we experienced production interruptions in 2005, 2006 and 2007 from Hurricanes Katrina and Rita and in 2008 and 2009 from Hurricanes Gustav and Ike for which we had no production interruption insurance.

We reevaluate the purchase of insurance, policy limits and terms annually each April. Future insurance coverage for our industry could increase in cost and may include higher deductibles or retentions. In addition, some forms of insurance may become unavailable in the future or unavailable on terms that we believe are economically acceptable. No assurance can be given that we will be able to maintain insurance in the future at rates that we consider reasonable and we may elect to maintain minimal or no insurance coverage. We may not be able to secure additional insurance or bonding that might be required by new governmental regulations. This may cause us to restrict our operations in the Gulf of Mexico, which might severely impact our financial position. The occurrence of a significant event, not fully insured against, could have a material adverse effect on our financial condition and results of operations.

We maintain an Oil Spill Response Plan (the Plan) that defines our response requirements and procedures and remediation plans in the event we have an oil spill. Oil Spill Response Plans will generally be approved by the BSEE bi-annually, except when changes are required, in which case revised plans are required to be submitted for approval at the time changes are made. We believe the Plan specifications are consistent with the requirements set forth by the BSEE.

The Company has contracted with an emergency and spill response management consultant, which would provide management expertise, personnel and equipment, under the supervision of the Company, in the event of an incident requiring a coordinated response. Additionally, the Company is a member of Clean Gulf Associates (CGA), a not-for-profit association of producing and pipeline companies operating in the Gulf of Mexico and has capabilities to simultaneously respond to multiple spills. CGA is structured to provide an effective method of staging response equipment and providing spill response for its member companies in the Gulf of Mexico. CGA has chartered its marine equipment to the Marine Spill Response Corporation (MSRC), a private, not-for-profit marine spill response organization which is funded by the Marine Preservation Association (MPA), a member-supported, not-for-profit organization created to assist the petroleum and energy-related industries by addressing problems caused by oil spills on water. MSRC owns and operates a fleet of dedicated Oil Spill Response Vessels (OSRV), ocean-going barges, shallow water skimming systems, other response equipment and enhanced communications capabilities in various regions including the Gulf of Mexico. MSRC maintains CGA s equipment in various warehouse locations (currently including, according to CGA s website, 14 skimming vessels with capacities ranging from 3,000 to 43,000 barrels per day, 17 skimmers with capacities up to 3,770 barrels per day, numerous containment and storage systems including thousands of feet of boom and two fire boom systems, tanks and storage barges, wildlife cleaning and rehabilitation facilities, both aerial and vessel dispersant spray systems and more than 33,300 gallons of dispersant) at staging points around the Gulf of Mexico in its ready state. In the event of a spill, MSRC mobilizes appropriate equipment to CGA members. In addition, CGA maintains a contract with Airborne Support Inc., which provides aircraft and dispersant capabilities for CGA member companies.

Additional resources are available to the Company on an as-needed basis other than as a member of CGA, such as those of MSRC. MSRC has oil spill response equipment independent of, and in addition to, CGA s equipment. MSRC s capabilities are augmented by a network of over 100 participants in the Spill Team Area Responders (STARs) program, an affiliation of environmental response contractors located at over 200 locations throughout the country. MSRC s equipment currently includes, according to MSRC s website, 15 oil spill response vessels with temporary storage for 4,000 barrels of oil and the ability to separate oil and water; 19 oil spill response barges with storage capacities between 12,000 and 68,000 barrels; 68 shallow water barges;

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600,000 feet of boom; over 240 skimming systems; six self-propelled skimming vessels; seven mobile communication suites comprising telephone and computer connections and marine, aviation and business band radios; various small crafts and shallow water vessels; two dispersant aircraft; and four dispersant/spotter aircraft. In the event of a spill, MSRC activates contractors as necessary to provide additional resources or support services requested by its customers.

The response effectiveness, equipment and resources of these companies may change from time-to-time and current information is generally available on the websites of each of these organizations. There can be no assurances that the Company, together with the organizations described above will be able to effectively manage all emergency and/or spill response activities that may arise and any failures to do so may materially adversely impact the Company s financial position, results of operations and cash flows.

Item 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS.

Issuer Purchases of Equity Securities

Period	Total Number of Shares Purchased	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs (1)	Maximum Number (or Approximate Dollar Value) of Shares that May Yet Be Purchased Under the Plans or Programs (1) (in thousands)
May 2012	130,800	$ 15.31	130,800	$ 22,102
June 2012	100,000	$ 15.95	100,000	$ 20,507
Total	230,800	$ 15.59	230,800	$ 20,507

(1) On August 29, 2011, we announced that the Board of Directors authorized a program for the repurchase of shares of our outstanding common stock for up to an aggregate cash purchase price of $20.0 million. On May 2, 2012, the Board of Directors authorized an increase to the program from $20.0 million to $40.0 million. We are funding the stock repurchases out of cash on hand. The repurchased shares will be accumulated and held in treasury. The repurchases are carried out in accordance with certain volume, timing and price constraints imposed by the SEC s rules applicable to such transactions. The amount, timing and price of purchases otherwise depend on market conditions and other factors.

Item 3. DEFAULTS UPON SENIOR SECURITIES.

None

Item 4. MINE SAFETY DISCLOSURES.

None

Item 5. OTHER INFORMATION.

None

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Item 6. EXHIBITS.

The exhibits marked with the cross symbol ( ) are management contracts or compensatory plans or arrangements filed pursuant to Item 601(b)(10)(iii) of Regulation S-K. We have not filed with this Quarterly Report copies of the instruments defining rights of all holders of the long-term debt of us and our consolidated subsidiaries based upon the exception set forth in Item 601(b)(4)(iii)(A) of Regulation S-K. Copies of such instruments will be furnished to the SEC upon request.

Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File Number	Exhibit	Filing Date	Filed/ Furnished Herewith
2.0	Second Amended Joint Plan of Reorganization of Energy Partners, Ltd. and certain of its Subsidiaries Under Chapter 11 of the Bankruptcy Code, as Modified as of September 16, 2009	10-Q	001-16179	2.0	05/06/2010	
2.1	Purchase and Sale Agreement dated January 13, 2011, by and between Anglo-Suisse Offshore Partners, LLC and Energy Partners, Ltd.	8-K	001-16179	2.1	01/18/2011	
2.2	Purchase and Sale Agreement dated October 28, 2011, by and between Stone Energy Offshore, LLC and Energy Partners, Ltd.	8-K	001-16179	2.1	11/02/2011	
2.3	Purchase and Sale Agreement dated May 15, 2012, by and between W&T Offshore, Inc. and Energy Partners, Ltd.	8-K	001-16179	2.1	05/21/2012	
2.4	Assignment and Bill of Sale dated as of May 15, 2012, by and between W&T Offshore, Inc. and Energy Partners, Ltd.	8-K	001-16179	2.2	05/21/2012	
3.1	Amended and Restated Certificate of Incorporation of Energy Partners, Ltd. dated as of September 21, 2009	8-A/A	001-16179	3.1	09/21/2009	
3.2	Second Amended and Restated Bylaws of Energy Partners, Ltd.	8-A/A	001-16179	3.2	09/21/2009	
4.1	Indenture by and among Energy Partners, Ltd., as Issuer, the Guarantors named therein and U.S. Bank National Association, as Trustee dated February 14, 2011	8-K	001-16179	4.1	02/15/2011	
4.2	Supplemental Indenture by and among Anglo-Suisse Offshore Pipeline Partners, LLC, as a Guarantor, Energy Partners, Ltd., as Issuer, the other Guarantors named therein and U.S. Bank National Association, as Trustee dated March 14, 2011	S-4	333-175567	4.2	07/14/2011	
31.1	Certification of Principal Executive Officer of Energy Partners, Ltd. pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.					X
31.2	Certification of Principal Financial Officer of Energy Partners, Ltd. pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.					X
32.1						X

	Section 1350 Certification of Principal Executive Officer of Energy Partners, Ltd. pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.	
32.2	Section 1350 Certification of Principal Financial Officer of Energy Partners, Ltd. pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.	X
101.INS*	XBRL Instance Document	X
101.SCH*	XBRL Taxonomy Extension Schema Document	X
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase Document	X
101.LAB*	XBRL Taxonomy Extension Label Linkbase Document	X
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document	X

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* In accordance with Rule 406T of Regulation S-T, the XBRL related information in Exhibit 101 to this Quarterly Report on Form 10-Q is furnished and shall not be deemed to be filed for purposes of Section 18 of the Exchange Act, or otherwise subject to the liability of that section, and shall not be part of any registration statement or other document filed under the Securities Act or the Exchange Act, except as shall be expressly set forth by specific reference in such filing.

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SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

ENERGY PARTNERS, LTD.

Date: August 2, 2012

By: /s/ Tiffany J. Thom
Tiffany J. Thom
Senior Vice President and Chief Financial Officer

(Principal Financial Officer)

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